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March 15, 2004

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PUBLIC SERVICE COMMISSION

Mr. Thomas M. Dorman
Executive Director
Public Service Commission of Kentucky
211 Sower Blvd.
P. O. Box 615
Frankfort, KY 40602-0615

**SERVED ON THE PSC BY DEPOSITING IN OVERNIGHT BOX ON 03/15/2004**

**RE: Kentucky Public Service Commission**
**Case No. 2002-00475, Kentucky Power Company**

Dear Mr. Dorman:

Enclosed please find and accept for filing the original and ten (10) copies each of the Prepared Testimony of Andrew Ott and Robert O. Hinkel on behalf of PJM Interconnection, L.L.C., Intervenor herein, in relation to the pending rehearing of the above-styled case and in response to the Cost Benefit Analysis filed by Kentucky Power Company d/b/a American Electric Power. Copies have been served on all parties of record.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Brent L. Caldwell

BRENT L. CALDWELL

BLC:dmp
Enclosure
cc: Counsel of record
p:\dianep\caldwell\pjm\dorman letter

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MAR 15 2004

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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| APPLICATION OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218 | ) | Case No. 2002-00475 |

**CERTIFICATE OF SERVICE**

This is to certify that a true and correct copy of the Prepared Testimony of Robert O. Hinkel on behalf of PJM Interconnection, L.L.C. with attached exhibits and the Prepared Testimony of Andrew L. Ott on behalf of PJM Interconnection, L.L.C. with an attached exhibit, were served as follows:

Originals and ten (10) copies were deposited in the Night Drop Box on the 15th day of March, 2004, at the:
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Copies of the Prepared Testimony were served via U.S. mail, postage pre-paid on the 15th day of March, 2004, upon:

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Respectfully submitted,

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# COMMONWEALTH OF KENTUCKY
# BEFORE THE PUBLIC SERVICE COMMISSION

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**In the Matter of:**

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| **APPLICATION OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218** | ) | **Case No. 2002-00475** |

**PREPARED TESTIMONY OF**
**ROBERT O. HINKEL**
**ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

**MARCH 15, 2004**

**REHEARING PREPARED TESTIMONY OF ROBERT O. HINKEL**

**ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

**Q. Please state your name and business address.**

**A.** My name is Robert O. Hinkel, and my business address is PJM Interconnection, L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania, 19403-2497.

**Q. What is your current position with PJM Interconnection, L.L.C. ("PJM")?**

**A.** I have been employed since May, 2002 by PJM as its General Manager of RTO Integration and Coordination. In that capacity, I am responsible for the management of activities associated with the integration of new transmission systems into PJM.

**Q. Are you the same Robert O. Hinkel who testified previously in this proceeding?**

**A.** Yes.

## I. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

**A.** In its August 25, 2003 Order on Rehearing, the Commission granted rehearing to PJM and to Kentucky Power in order for the two parties to "provide additional testimony on the issues set forth in their respective petitions for rehearing" as well as file and address a Kentucky-Power specific cost/benefit analysis. My testimony will address those issues raised by PJM on rehearing, and certain issues related to AEP's cost/benefit study filed in this rehearing. In particular, my testimony will provide further discussion on the following areas which were raised in PJM's Petition for Rehearing: curtailments, generation adequacy, PJM markets and congestion management, PJM's voluntary markets, and the costs of RTO membership. Andrew Ott of PJM addresses the bulk of the issues surrounding AEP's cost/benefit analysis in his testimony.

## II. PROFESSIONAL EXPERIENCE AND QUALIFICATIONS

**Q. Please describe your prior professional experience.**

**A.** I have more than 30 years experience in electric utility operations, facility planning, and information technology, including, most recently, overall responsibility for implementation of the PJM West project. I managed PJM West implementation from the start of project scoping work in January 2001 until the in-service date in April 2002, after which I assumed my current position. From 1998 to 2001, I was PJM's Manager of Capacity Adequacy Planning. Prior to joining PJM, I was employed for more than 27 years by Pennsylvania Power and Light Company (now PPL Electric Utilities) where I worked in various technical and managerial roles in electric system operations, delivery planning, and information services. I earned the degree of Bachelor of Science in Electrical Engineering from Drexel University in 1971. I am a registered Professional Engineer in the Commonwealth of Pennsylvania.

## III. GENERATION ADEQUACY

**Q. In its July 17, 2003 Order ("Order") the Commission stated: "...(G)eneration adequacy costs are still being debated within PJM and have not yet been established. This means that Kentucky Power could be required to pay twice for adequate generating reserves; once through its owned and purchased generation, and again through PJM tariff charges." (Order at 15). Does this finding accurately**

**reflect how generation adequacy is addressed in PJM and specifically how it would be addressed for Kentucky Power?**

**A.** PJM appreciates the opportunity to clarify this point. As an RTO, PJM is responsible for maintaining the short-term reliability of the electric transmission grid. As part of this responsibility PJM must assure that its members who are load serving entities (LSEs) have arranged for sufficient firm generating capacity to meet their capacity obligations as defined in PJM Agreements. The term "capacity obligation" means the obligation of each entity serving load in the region (for example, co-ops, municipal utilities and Kentucky Power) to have sufficient "stand by" capacity that it owns or has under contract to meet its obligations to serve its native load customers including sufficient reserve for contingencies. Contingencies could include such events as weather abnormalities or the unexpected loss of a generating unit (known as a forced outage). The PJM capacity requirement ensures that adequate generation is available under peak load conditions to serve overall energy demand and to maintain system reliability. In PJM, the Capacity Resources committed to meet an LSE's capacity requirements must be associated with specific generating units that can be called on to provide energy at times of peak load conditions or during generation-related emergencies. At such times the reliability of the system requires that the energy output of these Capacity Resources is available for delivery to PJM region load

Companies that own their own generation such as AEP, or have a contractual entitlement with generators to cover load, identify such resources as "Capacity Resources" to meet their PJM capacity obligation. Under those circumstances those companies do not pay any additional charge to PJM to cover their capacity obligations.

By contrast, capacity costs are incurred in generation emergency circumstances by those load serving entities that do not own sufficient capacity nor have a contractual entitlement to capacity to cover their load. Kentucky Power is not in that position, so it does not "pay twice for capacity." In fact, just the opposite is true: to the extent that AEP as a whole has excess generation (over and above that needed to meet its PJM obligations), AEP can sell that capacity and energy into PJM markets and receive revenues which could be eligible to flow through to AEP retail customers.

**Q. How do PJM's capacity adequacy requirements compare to the present capacity requirements for Kentucky Power and AEP?**

**A.** PJM's capacity adequacy requirements are comparable to the capacity reserve standards promulgated by ECAR. Specifically, today AEP is required pursuant to ECAR guidelines to have adequate capacity to meet a loss of load probability standard of one day in ten years. AEP can meet this obligation through its own installed generation ("iron in the ground") or firm capacity under contract to meet those ECAR requirements. Those obligations are reviewed by NERC, ECAR and this Commission. By the same token, capacity obligations are set by PJM based on two year forward forecasts of peak load and the historical performance of generation capacity within the PJM pool utilizing a similar loss of load probability analysis.

**Q. How will PJM's capacity adequacy protocols enhance reliability for native load (Order at 15)?**

**A.** PJM's capacity adequacy protocols enhance native load reliability by ensuring that actual capacity is available to meet native load obligations. In effect, PJM rules enforce the ECAR loss of load probability standard by requiring and documenting a contractual commitment that firm capacity to provide energy under peak load and emergency conditions will be available. PJM rules enhance reliability by establishing a definitive obligation to ensure that capacity is available on a given day and available when it is needed to protect native load, rather than being committed elsewhere. Other systems have experienced issues with entities having sold generation elsewhere, despite "paper commitments" to meet system load obligations. The PJM rules ensure that one system is not able to "lean" on another to maintain reliability in such circumstances.

**Q. Another issue raised by the Kentucky Commission is the effect that PJM's establishment of its reserve margin may have on the Commission's ability to review how AEP meets reserve requirements (Order at 20). How will the Commission's ability to review the manner in which AEP meets its reserve requirements be affected by AEP joining PJM?**

**A.** Today ECAR utilizes NERC planning standards to establish a reserve margin for the entire ECAR region. Load serving entities in PJM are required to sign the Reliability Assurance Agreement ("RAA"). The RAA is intended to ensure that adequate capacity resources are planned, coordinated, and made available to provide reliable service consistent with the development of a robust and competitive wholesale marketplace. The RAA clarifies PJM's role in ensuring that the reserve margin is actually met. The PJM RAA provides, as I've discussed, for the establishment of a firm capacity obligation and ensures that load serving entities identify and account for specific generating capacity to fulfill this obligation. A load serving entity (LSE) has various options for meeting this requirement. An LSE may "self supply" by using generation resources it owns directly. Alternatively, an LSE may obtain capacity to meet its reserve obligation by entering into bilateral contracts with other resource owners.. PJM provides its members with internet based transaction systems to manage the ownership and bilateral trading processes. Another option is for an LSE to rely on PJM's capacity markets for its resources PJM has developed both short term and long term capacity markets to provide load servers and capacity owners with a market-based solution for meeting capacity obligations.

**Q. How would Kentucky Power's capacity obligation under the PJM Agreements affect the authority of this Commission to examine and review Kentucky Power's reserve margin?**

**A.** AEP joining PJM does not diminish the Commission's ability to review the fact-specific circumstances surrounding AEP and its Kentucky operations as it does today. Pursuant to my understanding of 807 Kentucky Administrative Regulation 5:058, AEP would continue to file an Integrated Resource Plan triennially with the Commission in accordance with administrative requirements specifying the format and content of the report. Subsequent to its review, the Commission Staff would issue an Integrated Resource Planning report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings, as it does today; and the utility would continue to be required to respond to the staff's comments and recommendations in its next Integrated Resource Plan filing.

With these mechanisms in place today and in the future if AEP becomes a member of PJM, the consideration of the unique company-by-company circumstances as to how that reserve margin is met (i.e. whether the company purchases firm capacity, builds new generation or manages demand) as well as the siting of new generation remains a matter between the Company and the state pursuant to applicable regulatory laws.

PJM sets a reserve margin for its load serving entities that is consistent with the ECAR loss of load probability guideline of one day in ten years. This is the same benchmark presently utilized by AEP and virtually every utility in the Eastern Interconnection. PJM does not determine the type of power plant that should be built to meet the reserve margin – that is determined by the utilities and in the case of Kentucky Power, potentially reviewed by the state through the Integrated Resource Planning Process (IRP). When AEP joins PJM, nothing will impact or take away from the state's ability to review those planning decisions of the Company (AEP) to the extent the Commission does so today.

The integration of AEP into PJM is expected to result in a modest decrease in the reserve obligations of PJM as a whole and is expected to have minimal if any impact on the level of capacity resources required for AEP.

## IV. PJM MARKETS AND CONGESTION MANAGEMENT

**Q. In its original Order, the Commission indicated concern that Kentucky customers will not experience benefits from the creation of a larger wholesale market (Order at 18.) "Kentucky Power's base load generation has at or near the lowest cost of generation in both AEP-East and PJM, so how will being a part of the PJM market bring any quantifiable benefit to Kentucky Power and the customers of Kentucky Power?" (Order at 19). What benefits will Kentucky's retail customers receive from locational marginal pricing?**

**A.** PJM employs locational marginal pricing (LMP) to ensure efficient dispatch and transparency of pricing of wholesale energy on the transmission grid. LMP allows one to establish the actual cost of transmitting electricity over the electric grid, by considering the actual physics of electricity flow and the feasibility of dispatching location-specific generation in order to maintain reliable operations of the grid. At times when the grid is congested, it may be necessary to dispatch relatively more expensive generation in order to maintain system reliability, because the dispatch of lower cost generation would result in undue congestion. LMP is a method for capturing the costs of redispatching generation under those circumstances, and attributing those costs to the demand that caused the congestion, notwithstanding the protection from congestion that native load customers are provided through bilateral contracts and financial transmission rights (FTRs). Under PJM rules, native load customers are by and large protected from the costs of congestion through FTRs allocated to the load serving entities which serve native load customers.

In addition to making explicit the actual cost of transmitting power, LMP provides PJM system operators with a sophisticated tool to ensure reliability. PJM operators can send LMP price signals that encourage generators to increase or decrease generation at specific locations on the grid, as is needed to manage the flow of energy on transmission facilities.

LMP provides a direct benefit to Kentucky retail consumers in several other ways. By providing accurate signals about where congestion exists on the system, LMP informs decisions regarding the planning and siting of new generation and transmission facilities. Developers can review LMP prices to determine where the transmission system is congested; those locations are by definition candidates for infrastructure development. And, because LMP reveals the actual costs attributable to congestion along a transmission path, load serving entities are able to consider such information in assessing whether to reschedule transmission to lower congestion costs, resulting in more efficient use of generation and potentially lower fuel costs.

I understand that the Commission has found that existing transmission facilities are adequate to serve Kentucky's native load at this time, but at some point, additional generation, be it merchant generation or regulated generation will seek to be sited in Kentucky. Kentucky's siting authorities can use the historical LMP data to determine the potential effects on congestion of locating a plant at a particular site. As well, when alternatives to congested paths are scarce, authorities and stakeholders are informed that building new transmission might be appropriate. LMP provides a clear signal indicating where transmission should be enhanced to bolster system capability to deliver power.

A siting decision that does not take into account congestion considerations may well result in Kentucky customers bearing increased fuel costs incurred in redispatching generation units to alleviate the congestion. This could occur during congested periods when the least cost generation cannot be used due to system constraints. Furthermore, because the Commission can utilize ratemaking tools to provide that Kentucky retail customers share in profits derived from AEP's off-system sales, they will directly benefit from improved management of congestion at the seam that exists today between AEP and PJM. AEP's full integration into PJM will provide for LMP-informed generation redispatching at the present-day AEP-PJM seam, enabling potential additional AEP off-system sales and thereby benefiting Kentucky retail customers.

**Q. When there is no congestion will the use of LMP on the Kentucky Power portion of AEP's transmission system actually increase costs for Kentucky Power consumers (Order at 20)?**

**A.** AEP maintains consistent with PJM's own analyses that at the present time there is not any significant congestion on the AEP-East system. (Direct Testimony of Craig Baker at p. 11). When there is no significant congestion, there is no significant difference between LMPs at different system nodes. As a result, there are no significant congestion-related transportation costs. LMP-based congestion costs are relevant only when congestion exists on the system, as reflected in the differential of LMP costs at distinct system nodes.

## V. PJM's VOLUNTARY MARKETS

**Q. In its Order the Commission suggested that it would be possible for PJM to change its market rules to require all generation to be sold into the market, thereby significantly raising costs for Kentucky Power customers (Order at 20). Is it possible for PJM to take this action?**

**A.** Rather than focus on unsubstantiated possibilities, I believe the Commission should focus on the Application before it, which will maintain reliability and reduce prices. The PJM model has functioned well both for bundled and unbundled states. Realistically, PJM will not change its market rules to require all generation to be sold into the market. PJM has no motive, no intention, and no reason to attempt to enact such a change. PJM was established in order to ensure open and non-discriminatory access to the grid. PJM's dispatch is intended to provide a reliable and coordinated transmission system that operates independently of market participants. Requiring all generation to be sold into the market is completely counter to PJM's foundation principles as expressed in the Operating Agreement, and PJM's members would not allow such a result. Nor, in my opinion, would FERC authorize such an ill-advised change in the infinitesimally unlikely and entirely unforeseeable event that some unidentified entity petitioned it to do so.

Furthermore, the agreements, business rules and processes associated with the various PJM markets have been developed through an extensive stakeholder process dating back to the initial formation of PJM as an Independent System Operator in the later 1990's. As such, PJM's agreements, business rules and processes represent the integration of consensus or compromise views discussed extensively with the state commissions in the PJM footprint, and subsequently approved by the members, the PJM Board of Managers and the FERC. Any significant change to the structure of the PJM markets would need to be developed through this process and would therefore provide an adequate opportunity for all participants to provide their input and guidance to the course of potential changes.

**Q. If PJM's markets are indeed voluntary, why are bids into PJM's capacity market required by designated "capacity resources?"**

**A.** In answering this question, it is important to distinguish between capacity bids which are required to ensure reliability and energy bids which are entirely voluntary. Consistent with its obligation to assure reliable system operations, PJM maintains a Reliability Assurance Agreement (RAA) which requires each load-serving entity to own or purchase Capacity Resources greater than or equal to the load that is serves, plus a reserve margin. Only in the event of a capacity emergency, in which there is insufficient capacity to meet system demand, is PJM authorized, pursuant to the RAA, to "call on" the capacity bid into the market in order to balance supply and demand. While it is true in a literal sense that the RAA and the PJM Operating Agreement mandate that capacity be bid into the energy market by load-serving entities under certain circumstances, PJM is merely using the market in this instance as a mechanism to assure reliable operations. The situation only is for capacity and only to ensure reliability. It is in no way analogous to the specter of a mandatory energy market, into which all energy would be required to be bid.

PJM rules establish that owners of Capacity Resources may utilize those resources to "self-schedule" or to bid into the PJM energy market: bids into the PJM energy market are voluntary. If a Capacity Resource is self-scheduled or committed as a result of a bilateral transaction within PJM, it is not required to enter a bid in the energy market. A Capacity Resource that voluntarily bids into the PJM energy market, however, is being counted upon to meet PJM capacity obligations; for that reason, the RAA requires that those resources be available to PJM for energy production in the event of a capacity emergency.

Capacity Resources that bid into PJM's day-ahead energy market may or may not be scheduled for dispatch by PJM. If they are not scheduled to run, their owners may commit those resources via a bilateral sale, provided they maintain their energy output as recallable to PJM in the event of a capacity emergency. Again, the market in this instance is a mechanism which provides PJM with the assurance that it will have sufficient capacity to maintain reliability in a capacity emergency. The voluntary act of bidding into the energy market binds the bidder to make the capacity available at the bid price.

## VI. RTO COSTS

**Q. Is it possible that Kentucky Power will incur increased costs due to membership in PJM without receiving a pro rata share of increased revenues? (Order at 16).**

**A.** Before addressing how membership costs to which AEP would be subject should be considered in evaluating net benefits, it is important to know how PJM recovers its costs through the administrative cost recovery provisions in Schedule 9 of its Open Access Transmission Tariff (OATT). PJM has unbundled the administrative costs in that tariff, so that PJM members pay for the PJM services they use. These costs are all subject to FERC review and are also open for examination by the Kentucky PSC.

The cost/benefit study that AEP has submitted in this proceeding, as well as the testimony of my colleague Andrew Ott in this rehearing, directly addresses the question the Commission has raised by establishing that a significant net benefit (a benefit greater than the cost of membership) will result from the full integration of AEP into PJM . In addition to the unquantified benefits of an organized independent regional planning process and the availability of a market monitor to detect abuses in the marketplace, full integration will, among other things, offset AEP membership costs by allowing AEP to realize increased profits from off-system sales and increased market efficiencies.

**Q. What are your comments on AEP's Case IA, its "partial integration" concept?**

**A.** AEP has presented a cost benefit analysis earlier in this proceeding which demonstrated that benefits associated with AEP's full integration into PJM significantly outweigh the costs of joining PJM. As my colleague Andrew Ott discusses in his testimony, the full integration scenario and limited integration concept that AEP has modeled do not take into account the full range of respective costs and benefits that should be considered.. As a result, I disagree that on balance AEP's partial integration scenario is a better alternative than is the full integration scenario. Nevertheless, even prior to the necessary modeling adjustments noted by my colleague Mr. Ott, AEP's cost benefit study shows that Kentucky Power will not incur undue increased costs by joining PJM..

**Q. Are the costs associated with AEP's Case IA accurate in your view?**

A. No, I believe the benefits of this concept are overstated and the costs are understated. In AEP's partial integration concept, AEP incorrectly assumed that membership costs for PJM would be approximately equivalent to the costs that were forecasted for its participation in the Alliance RTO. The costs of Alliance membership are not a good proxy for PJM's membership costs for several reasons. First, the Alliance cost estimates were only conceptual, were never tested by implementation, and were developed three years ago. Second and even more importantly, the Alliance administrative costs estimate is not inclusive of the full range of services that would be provided by PJM, even under a partial integration concept. Although I have not performed a detailed assessment of the actual costs of the partial integration concept, I believe its assumptions regarding administrative costs significantly underestimate the true costs of partial integration in PJM and consequently skew the results to suggest higher net benefits than are warranted in Case IA.

To determine the true net benefit of the partial integration scenario, I take into account that the AEP study understated administrative charges and overstated off-system sales benefits. When viewed in this manner, I conclude that the AEP full integration scenario provides the higher net benefit..

**Q. The Kentucky Commission has expressed concern about "surrendering even a portion of its authority to protect Kentucky Power's customers" and determined that the transfer of control of a utility's transmission system should be handled cautiously. (Order at 20). If AEP joins PJM will the Kentucky Commission retain authority to appropriately protect the consumers of Kentucky Power?**

**A.** Although I am not testifying as a lawyer, based on my experience both with PJM and with a state regulated utility, I do not believe that there is any aspect of AEP's membership in PJM that infringes on the Commission's authority. For example, PJM does not set transmission rates, either retail or wholesale. Although it undertakes a regional planning process, the results of that process are still subject to state siting laws, and the Kentucky Commission will benefit from the additional information that the regional planning process provides. The PJM market monitoring plan expressly provides for the market monitor to undertake studies or analyses at the request of state commissions. On the contrary, the Kentucky Commission will have additional tools at its disposal in order to exercise its jurisdictional authority as it sees fit.

**Q. Would AEP retain the right to manage their transmission rates as they do today (Order at 20)?**

**A.** Yes. PJM does not determine the rates that transmission owners charge to their customers. As a member of PJM, AEP would continue to files its proposed transmission rates with FERC for approval under the OATT. PJM collects and distributes revenue to the transmission owners as an independent overseer, but PJM does not determine the amount of the rates and revenues.

## VII. EMERGENCY CURTAILMENT

**Q. The July 17th Order notes that KRS 278.214 requires that, "when a Kentucky utility or generation and transmission cooperative experiences an event that necessitates curtailment or interruption of service, its customers within its certified retail territory must be the last to suffer the curtailment or interruption." (Order at 20). If AEP were to join PJM, would native load customers be protected from curtailment or interruption of service?**

**A.** My understanding of this statute is that from a practical perspective, KRS 278.214 establishes that native load customers may be curtailed only under circumstances so severe that their curtailment is necessary to "relieve an emergency or other event." This is precisely the manner in which PJM would approach a reliability situation. Only in those rare circumstances where an emergency is so acute as to require massive curtailments across PJM to keep the lights on, would PJM call for a curtailment level that would leave Kentucky Power and the Commission with no discretion to target curtailments to maintain service to native load. Virtually all actual circumstances that would require local curtailment are due to local reliability considerations; in such circumstances the local utility, and not PJM, would make the actual curtailment decisions.

There are several aspects of how PJM addresses curtailment. In the first place, protocols covering curtailments of native load customers are matters between Kentucky Power and the Commission. PJM does not get involved in such determinations. If it were necessary to curtail load to assure system reliability, PJM would provide an instruction to AEP which would then determine, based on the nature of the circumstances, where and which customers to curtail within its system. Second, AEP's joining PJM actually works to reduce the likelihood of curtailments of Kentucky native load customers. System operators will be able to redispatch resources across a broader footprint to keep energy flowing to native load customers in Kentucky, in the rare circumstances in which continuity of supply is threatened. Third, where unanticipated loss of generation results in a capacity emergency outside of AEP, PJM will not curtail Kentucky native load customers to resolve the capacity emergency situation. Fourth, the scope of local rather than regional or system-wide energy emergencies provides Kentucky Power with discretion to target curtailments. Fifth, I reiterate that curtailment of native load customers would only occur if absolutely necessary to resolve an emergency. Finally, I would like to reiterate that PJM is committed to work the Kentucky Commission to ensure that PJM's protocols are in full compliance this statute.

**Q. Does this conclude your testimony?**

**A.** Yes, it does.

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PUBLIC SERVICE
COMMISSION

# COMMONWEALTH OF KENTUCKY
# BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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| APPLICATION OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218 | ) | Case No. 2002-00475 |

## PREPARED TESTIMONY OF
## ANDREW L. OTT
## ON BEHALF OF PJM INTERCONNECTION, L.L.C.

MARCH 15, 2004

## PREPARED TESTIMONY OF ANDREW OTT ON BEHALF OF PJM INTERCONNECTION, L.L.C.

**Q. Please state your name and business address.**

**A.** My name is Andrew L. Ott, and my business address is PJM Interconnection, L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania, 19403-2497.

**Q. What is your current position with PJM Interconnection, L.L.C. (PJM)?**

**A.** I have been employed since October, 1996 by PJM as its Executive Director of the Market Services Division. In that capacity, I am responsible for the management of the PJM Market Operations and Market Settlements. I am also responsible for development and oversight of PJM Market Design changes.

**Q. Are you the same Andrew L. Ott who testified previously in this proceeding?**

**A.** Yes.

### I. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

**A.** The purpose of my testimony is to provide additional information and observations concerning the AEP cost benefit study that has been submitted to the Kentucky Commission, in response to the Commission's July 17 Order and the Commission's Order on Rehearing in which the Commission observed that there is no quantification of benefits to Kentucky Power" as a result of membership in PJM (Order at 21). I have reviewed the cost benefit study provided by AEP. I am testifying in order to set forth my observations concerning the analysis and to suggest how the Commission should address the cost benefit issue as a result. I will also explain that the quantifiable benefits that are the consequence of AEP becoming fully integrated in PJM will result in benefits that exceed the administrative costs associated with membership in PJM. I will specifically address the Kentucky Commission's concerns that, first the quantifiable benefits shown must offset the costs of joining PJM and second to show that additional benefits should accrue to Kentucky Power customers as a result of AEP's decision to join PJM. (Order on Rehearing at 5)

**Q. What is your overall conclusion concerning the AEP cost benefit study?**

**A.** The general methodology utilized by AEP is sound and has been utilized in similar analyses. I concur with AEP that there are clear demonstrable benefits for Kentucky customers from AEP fully integrating into PJM. But for reasons I explain herein, I find that AEP's estimates of the benefits of full integration of AEP into PJM in Case I are conservative. On the other hand, I do not believe that AEP's analysis of the costs and benefits of Case IA, its "partial integration" concept, is correct or reliable for use by this Commission because of modeling inaccuracies that I describe herein. In addition, the benefits that AEP identifies for Case IA are problematic because "partial integration" is merely a conceptual proposal.

## II. PROFESSIONAL EXPERIENCE AND QUALIFICATIONS

**Q. Please describe your prior professional experience.**

**A.** For PJM, I was responsible for implementation of the current PJM LMP system, the PJM Financial Transmission Rights Auction and the PJM Day-ahead Energy Market. Prior to joining PJM, I worked extensively in developing electricity market models and power system analysis applications. In carrying out my market design responsibilities at PJM, I have gained extensive experience in working with electricity market modeling tools, including the GE-MAPS program, to develop computer-based market simulations. I have received a Bachelor of Science in Electrical Engineering from Penn State University and a Master of Science in Applied Statistics from Villanova University.

**Q. Please summarize your work experience prior to joining PJM.**

**A.** Prior to joining PJM, I worked for General Public Utilities Service Corp. for 13 years as a transmission planning engineer and as a system planning engineer.

## III. AEP Cost Benefit Study

**Q. Are you familiar with AEP's cost benefit study that was submitted to this Commission?**

**A.** Yes, I have reviewed AEP's cost benefit study and testimony.

**Q. Please briefly explain the study.**

**A.** AEP has prepared a Kentucky Power specific cost benefit analysis that shows the effects of system operation changes associated with AEP's integration into PJM. The Study was based on simulations that were undertaken by the Cambridge Energy Research Associates (CERA) at the request of AEP. The Study addresses three scenarios. The base case scenario (denoted Scenario B and Case II in Mr. Baker's testimony, and hereafter referred to as Case II), is modeled with through and out rates in effect for AEP, and with existing dispatching regions in place. Two change cases are modeled: a "full integration" scenario (denoted Scenario A and Case I in Mr. Baker's testimony and hereafter referred to as Case I) in which through and out rates are assumed to be eliminated for the entire PJM/MISO footprint including Commonwealth Edison, Dayton Power & Light and Dominion Virginia Power, and a security constrained economic dispatch in place across an expanded PJM; and a "partial integration" concept (denoted

Scenario A and Case IA in Mr. Baker's testimony and hereafter referred to as Case IA) in which PJM provides only some functions for AEP, but AEP does not participate in PJM's energy markets nor its locational marginal pricing congestion management program. The AEP study evaluates the relative costs and benefits of each change case as compared to the base case, over a five year forecast period.

**Q. Do you have comments on the study methodology?**

**A.** Yes. Although I find the AEP study results for full integration conservative for the reasons detailed below, I would be remiss if I did not acknowledge that the general methodology utilized in the study for the analysis of Case I and Case II is based on a sound modeling technique which is consistent with many of the other studies that have been undertaken by various parties, including PJM, to assess costs and benefits of RTO participation. The study is based on performing a simulation using a recognized industry tool develop by General Electric and known as the GE-MAPS program to essentially dispatch the system by performing what is known as a unit commitment and security-constrained dispatch for several annual periods with and without various transmission charges known as wheeling rates being in effect.. The results of the simulations without wheeling rates are then compared to the results of the simulations with wheeling rates in order to calculate the economic benefits of the wheeling rate elimination.

In these types of studies, generally the wheeling rates are based on two components: 1) the transmission service charges for through (transactions that simply utilize the AEP system but do not have sources or sinks within AEP) and out transactions (transactions that represent exports of generation from the AEP control area) and 2) an estimated economic 'hurdle' rate which is added to represent the economic inefficiency associated with the lack of an integrated market.

**Q. You used the term "hurdle rate." Please explain that term and whether utilizing a hurdle rate is a common modeling technique.**

**A.** A "hurdle rate" is a straight-forward economic modeling technique used in distinguishing a base case and a change case. In the base case we are discussing in this proceeding, there are barriers to efficient trading between regions – in this instance, the AEP control area and PJM. In addition to transmission wheeling rates, there are costs associated with the relatively inefficient trading practices in place between trading and non-trading regions. These costs are in essence "hurdles" that are overcome in the change case. Said another way, the absence of the hurdle rate in the change case reflects the removal of barriers to efficient trade. Professional judgment and modeling experience is often required to establish appropriate hurdle rates. On the other hand, the impact of certain trading barriers is not a matter of judgment: for example, AEP's through and out rates are known, and AEP reflected their removal in Case I, the full integration change case. As I explain below, I analyzed the empirical impact of Allegheny Power joining PJM to determine an appropriate hurdle rate to model increased market efficiencies that can be expected to occur when AEP is fully integrated in PJM. Hurdle rates can be matters of judgment, but that does not mean that they are arbitrarily set.

**Q. Please continue with your comments about the AEP cost benefit study.**

**A.** Traditionally in these types of studies, the wheeling rates are modeled in both the forward scheduling (unit commitment) phase of the simulation (i.e. the "day ahead" scheduling of the units) and in the hourly dispatch phase of the simulation (i.e. "real time" variations from the day ahead schedule based on real time changes in load or generation from the day ahead forecast). In AEP's study, the wheeling rates for the hourly simulated dispatch were $4.25 per MWh which is equal to the current AEP transmission service charges. The economic hurdle rate component for the hourly simulated dispatch was assumed to be $0, which means that the study assumed no economic benefit associated with AEP's integration into a regional market dispatch. The AEP study did include a $3.00 adder as an economic hurdle rate in the unit commitment phase of the simulation and therefore did include some benefit for coordinated forward scheduling which will occur under market integration. However, my experience in the past PJM market implementations has indicated that significant economic benefit is derived from the dispatch coordination. The dispatch coordination that is achieved through full market integration results from elimination of trading inefficiencies that exist in areas without markets. Therefore it is appropriate to reflect the elimination of those inefficiencies with a reasonable economic hurdle rate value for the hourly simulated dispatch. I have conducted a study of the actual economic benefit of hourly dispatch that resulted from the integration of Allegheny Power into the PJM market to derive a reasonable economic hurdle rate value for the hourly simulated dispatch in Case IA, and discuss its significance below.

I believe that the AEP study underestimates net benefits in Case I, the full integration change case. AEP's full integration change case does not fully account for the efficiencies to be gained from the market efficiencies in fully coordinated regional dispatch which optimizes hourly energy flows over a broader geographical area. PJM would provide those market efficiencies if AEP were fully integrated. Realizing those efficiencies translates into increased economic sales. The net proceeds of those sales can flow back to customers under a system sales sharing arrangement via Kentucky's fuel adjustment regulatory processes.

**Q. Does this mean that AEP's study Case I is not applicable to this inquiry?**

**A.** Not at all. What is most important is that both AEP's Case I study and my analysis indicate there to be clear benefits to Kentucky customers from AEP's full participation in PJM. We are differing on the degree of benefit, not whether there will be a benefit. Through various Kentucky-specific rate processes, this Commission will be able to observe and capture the actual benefits consistent with its regulatory processes. I will leave the details of how those processes work to discussion between AEP witness Baker and Commission staff. However, it is noteworthy that both AEP's Case I study and my review of their analysis show a clear benefit to Kentucky customers.

**Q. You indicated that the AEP study is conservative in its analysis of the benefits of the full integration case, Case I. Please elaborate on your point and its significance to the state of Kentucky.**

**A.** A significant portion of the savings that occurs from large RTOs results from the capturing of greater efficiencies associated with a security constrained economic dispatch along with better management of transmission constraints near the interties between neighboring systems. Both are relevant to AEP's integration into PJM.

In the first place, it should be underscored that AEP can continue to dedicate its lowest cost units to serve its own native load customers. In PJM, AEP could do this by exercising its right to "self supply" its own load from its generating resources. While

AEP could do so absent any reliance on PJM's energy market, that market would provide a ready mechanism for AEP to derive profits from its generation in excess of that needed to serve its native load.

PJM operates a voluntary bid based market. This means that generating units are "stacked" in the order of bids received and matched with forecasted load on a day ahead basis. The marginal unit needed to meet load sets the market clearing price for all generating units. Because AEP's units are generally quite low cost, the market provides a transparent and ready source of sales of its low-cost generation over and above that needed to serve its native load. The transparency of the market – the fact that generation bids into the market are public knowledge - provides this Commission with an effective tool to monitor the reasonableness of AEP's off-system sales. In addition, the market provides additional opportunities for Kentucky to market low-cost coal-fired generation. Finally, should AEP be short or should there be lower cost generation available in a given hour, then AEP could be a buyer in the market on behalf of its native load customers.

My concern with AEP's study is that it fails to quantify the increased efficiencies associated with security constrained economic dispatch in Case I, the full integration scenario. Rather, it assumes that these efficiencies are already captured by today's more inefficient system of trading. Although traders can be quite good at what they do, absent price transparency, and the efficient transaction mechanisms that a market provides, there clearly are missed opportunities and inefficiencies associated with the bilateral phone call based system on which AEP operates today. My experience has shown that bilateral trading simply cannot achieve the same level of efficiency as a regional market can provide.

As an example, approximately 8 months after the integration of PJM West (Allegheny Power zone) into the PJM market, I performed an analysis to quantify the economic benefit of the market integration to customers in the Allegheny Power (AP) zone for the first 8 months of market operation. (Exhibit A) This analysis measured an economic benefit of $40,730,000 to AP customers over the 8 month period. This translates into a savings of approximately $1.50 per MWh of load served in the AP zone during the period. Since these measured savings were solely based on the improved efficiency of the regional economic dispatch[1], this result indicates that a dispatch hurdle rate of at least $1.50 would be an appropriate value to use in Case I to estimate savings to customers as a result of the increased efficiency of implementing a regional economic dispatch across areas that are currently under individual economic dispatch. I performed simulations using a 2005 GE-MAPS model to quantify the benefit of implementing a regional dispatch that includes AEP using a $1.50 economic hurdle rate assumption. This simulation indicated an economic benefit of approximately $35 Million in the AEP zone. As with the other studies, this benefit is derived from increased sales to other regions. I assume some of these additional benefits would be assigned to Kentucky customers in a manner similar to that described in the AEP study.

**Q. Are you able to estimate what proportion of this $35 Million benefit would accrue to Kentucky Power customers?**

**A.** AEP is best positioned to provide such an estimate. However, it is reasonable to utilize as a proxy the Member Load Ratio share of Kentucky Power to the AEP-East

[1] As stated in the attached memo report, these results do not include any benefits resulting directly from the elimination of transmission rate pancaking that occurred when PJM West was implemented.

system as a whole. Given the proportional benefit of approximately 7.3% that Kentucky Power today enjoys from off system sales, that allocation factor would result in a benefit associated with increased off system sales profit in 2005 of about $2,555,000. A portion of that profit would flow back to Kentucky native load customers through a system sales sharing arrangement in fuel adjustment proceedings. Over the five year study period, benefits to Kentucky native load customers attributable to such market efficiencies would be quite substantial. But AEP could provide a more definitive analysis, and I would reserve the right to consider savings magnitudes in light of their analysis.

**Q. You also analyzed AEP's Case IA which presents a "partial integration concept." Do you feel the benefits that AEP identified in Case IA are reasonably estimated?**

**A.** No, I do not. The study methodology that was employed for the analysis in Case IA contains several structural problems in the modeling technique. The first problem is that the Case IA analysis utilizes the simulation results (as reflected in off-system power sales) obtained in Case I, which simulates coordinated market operations across the region, including AEP. The use of these simulation results to measure economic benefits in Case IA is not valid because the partial integration implementation describe in Case IA does not contemplate the implementation of a regional market. The Case I simulation performs a combined unit commitment and dispatch over the combined region including AEP which does not adequately model the trading patterns that would exist with "partial integration"; therefore these results cannot reasonably be interpreted to measure benefit for Case IA. In other words, Case IA erroneously uses the results of a full integration model where there is an organized regional trading market to produce results for a concept where there is no such organized market.

Another issue with the Case IA modeling technique is that it does not account for the economic impact of trading barriers such as Transmission Line Loading Relief actions (TLRs) and other control area border scheduling issues that would continue to exist with partial integration. TLRs and difficulties in scheduling due to inconsistent rules where market areas abut non-market areas represent real barriers to the economic trading that Case IA allegedly reports. Because of these structural modeling problems, AEP's analysis tends to significantly *overstate* the economic benefit of Case IA.

**Q. Can you elaborate on the concerns that you have with the partial integration analysis concept, Case IA in the AEP study?**

**A.** Yes. As I stated previously, the AEP study analysis tends to significantly overstate the economic benefit in Case IA, the partial integration concept, because it uses a modeling technique that does not reflect the sub-optimal trading conditions that would exist under partial integration. The analysis also fails to account for the significant economic impact caused by interruption to power sales that occur today and would continue to occur under a partial integration construct in the region because of the continued dependence on the NERC TLR mechanism to manage transmission limitations at the borders between the control areas. Such TLR events interrupt sale transactions that AEP and other independent Kentucky generators would otherwise succeed in making, or which Kentucky cooperatives and municipals might otherwise seek to utilize to procure power.

In addition, there are currently significant loop flows at the PJM-AEP seam that must be managed utilizing TLRs, and would continue to be managed with TLRs with partial integration. The magnitude of the congestion that must be managed by TLRs is significant in this region. For example, the following are facilities in PJM and AEP on which congestion results from flows that cannot be managed by internal redispatch under the current configuration and that are frequently managed by TLRs rather than redispatch. (These flowgates are in the top ten facilities, by frequency of occurrence, for which TLRs have been called in 2003.) As an illustration of the significant loop flows between PJM and AEP, the volume of TLRs in PJM and AEP used to manage constraints has constituted 19 percent of all TLRs implemented in the U.S. since 1998.

| **Jointly Impacted Facilities Frequently Managed By TLRs** | |
|---|---|
| **Flowgate** | **Area** |
| Wylie Ridge Transformer | PJM |
| Cloverdale-Lexington | AEP |
| Kammer Transformer | PJM |
| Kanawha - Matt Funk | AEP |
| Erie West -Erie South | PJM |
| Bedington-Black Oak | PJM |
| Doubs Transformer | PJM |

The economic impact of these TLR events cannot be ignored when evaluating the economic impacts in Case IA.

**Q. You have described that TLR procedures result in less efficient interregional congestion management. Can you illustrate this impact with an example?**

**A.** Yes. Suppose there is a transmission constraint in one control area (e.g. AEP) that impacts interregional power transfers and that can most effectively be mitigated by operating a generating unit that is in the adjacent control area (i.e. PJM). If these control areas are operated under separate economic dispatch (e.g. as in Case IA), the control area operators in AEP would not have the ability to utilize the generator in PJM to control the constraint and they would therefore need to use the less efficient alternative, curtailing interregional transfers using the TLR mechanism, instead. To illustrate this point, let us assume that the PJM generator is a 50 MW unit with a $60/MWh production cost and that if the unit is operated, a 1000 MW increase in interregional power transfers could be supported because the transmission constraint was mitigated by the PJM unit operation. If this 1000 MW energy transfer can be produced for $10 per MWh less in AEP than it can in PJM, then the net savings that can be realized across the regions would be $7000 for one hour of operation. In this scenario, running the higher-cost 50-megawatt unit produces substantial net savings, because it also enables 1000 megawatts of less expensive generation to be operated in the adjacent region. If the control areas are operated separately, as they are today, the most effective transmission control alternatives may not be utilized for transmission constraints near the control area borders. Only a regional dispatcher with the ability to perform economic dispatch using units on both sides of the control area seam will effectively implement this sort of dispatch.

**Q. Is it possible to estimate the economic benefit reduction that would occur in the partial integration case if the TLR impacts were not ignored?**

**A.** Yes. To estimate the annual economic impact that would occur as a result of sale interruptions due to TLR events in the partial integration concept modeled as Case IA, we can utilize the historic frequency of occurrence of TLRs in the region. The number of hours of TLR events that occurred at the AEP-PJM and AEP-VP border are listed in the following table.

| Name | NERC Name | Number of Hours |
|---|---|---|
| Kammer Transformer | Kammer #8 xfmr I/o Belmont-Harrison 500 | 205 |
| Kanawha - Matt Funk | KANAWZ-M FUNK 345/BAKER-BROADFORD 765 | 684 |
| Cloverdale-Lexington | CLVRDL-LXNGTN500/PRUNTYTN-MT STM500 | 435 |
| Wylie Ridge Transformer | Wylie Ridge #7 345/500 xfmr I/o Wylie Ridge #5 345/500 xfmr | 383 |
| Wylie Ridge Transformer | Wylie Ridge #5 345/500 xfmr I/o Wylie Ridge #7 345/500 xfmr | 1566 |
| ERIE WEST Area | Erie West-Erie South 345 kV line | 79 |
| ERIE WEST Area | ERIES 345 KV ERIES 5 TX 3 XFORMER | 23 |
| ERIE WEST Area | ERIEW 345 KV ERIEW NO1 TX XFORMER | 165 |
| BEDINGTON - BLACK OAK | | 818 |
| BEDINGTON - BLACK OAK | 01BLACKO 500 01BEDNGT 500 1 | 27 |
| BEDINGTON - BLACK OAK | BLACKO-BEDNGT500-PRNTY-MTSTM500 | 22 |
| BEDINGTON - BLACK OAK | 01AQUEDT STATIONH 230-DOUBS STATIONH 230 | 15 |
| Doubs Transformer | DOUBS 500 KV DOUBS 500-1 XFORMER | 300 |
| Doubs Transformer | DOUBS 500 KV DOUBS 500-2 XFORMER | 38 |
| Doubs Transformer | DOUBS 500 KV DOUBS 500-3 XFORMER | 3 |
| Doubs Transformer | DOUBS 500 KV DOUBS 500-4 XFORMER | 1 |

An analysis of these TLR events indicates that the costs in 2003 to the region in lost power transfer opportunities because of the use of the TLR-based curtailments instead of using the a more efficient regional security-constrained economic dispatch is approximately $95 Million. This lost opportunity cost was used as a basis to develop an approximate reduction in AEP sale profits that would result from the less efficient TLR-based congestion management procedures. The analysis indicates that the annual sale profits would be reduced by between $5 and $7 Million. Therefore, such an annual reduction should be applied to the economic benefits quantified in Case IA to account for the lack of efficiency in managing interregional transmission congestion constraints.

**Q. Would you please summarize your testimony regarding the relative benefits of full and partial integration of AEP into PJM?**

**A.** Yes. Case IA (the full integration scenario) significantly understates net benefits because it does not account for benefits resulting from increased market efficiency. For the year 2005, the net benefits for AEP-East should be raised by $35 Million, from $37 million to $72 million. Kentucky's share of that net benefit for the year 2005 should be raised by $2.5 million, from $2.7 million to $5.2 million. It is reasonable to assume comparable incremental benefit in each of the five years of the study period, raising the total net benefit for the AEP-East Region in the full integration case over the five year study period to $373 million. The Kentucky share of the five year net benefit should be raised by $12.5 million, to $25.9 million.

These five-year study period Case I (full integration) net benefits of $373 million for AEP-East and $25.9 million for Kentucky are significantly higher than the net benefits that AEP estimated for Case IA, its partial integration concept, of $283 million for AEP-East and $20.3 million for Kentucky. Furthermore, the net benefit that AEP estimated for Case IA overstates net benefits for two reasons. First, AEP's Case IA estimate does not account for the $5 to $7 million annual costs associated with TLR interruption of AEP sales opportunities. Second, as my colleague Robert Hinkel points out in his rehearing testimony, AEP has likely underestimated the administrative costs that it would incur with "partial integration." After taking these adjustments and considerations into account, it is evident that Case I (full integration) provides a higher net benefit to the state of Kentucky than does Case IA.(partial integration concept).

**Q. Does this complete your testimony?**

**A.** Yes it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

| | |
|---|---|
| APPLICATION OF KENTUCKY POWER COMPANY d/b/a AMERICAN ELECTRIC POWER FOR APPROVAL, TO THE EXTENT NECESSARY, TO TRANSFER FUNCTIONAL CONTROL OF TRANSMISSION FACILITIES LOCATED IN KENTUCKY TO PJM INTERCONNECTION, L.L.C. PURSUANT TO KRS 278.218 | ) Case No. 2002-00475 |

**AFFIDAVIT**

Andrew L. Ott, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

ANDREW L. OTT

STATE OF PA )
) ss:
COUNTY OF Montgomery )

SUBSCRIBED, SWORN TO AND ACKNOWLEDGED before me, a Notary Public, by Andrew L. Ott, this 15 day of March, 2004.

My commission expires: 1/29/07

NOTARY PUBLIC

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Notarial Seal
Lisa L. Dessender, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Jan. 29, 2007
Member, Pennsylvania Association of Notaries

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## Evaluation of the Increase in the Economic Efficiency of the overall PJM Unit Commitment and Dispatch Economic Dispatch Resulting from the Integration of Allegheny Power into the PJM Energy Market

The purpose of this paper is to quantify the economic benefit that was achieved by increased efficiency in the security-constrained unit commitment and economic dispatch resulting from the integration of Allegheny Power into the PJM Energy Market. This integration was implemented on April 1, 2002. In order to quantify the benefits, the market prices, demand requirements and power transfers were analyzed for the period April 1, 2002 through November 30, 2002. The analysis focused on comparing actual PJM market results for the study period to a set of simulated results that were created to approximate the unit commitment and dispatch patterns that would have occurred had Allegheny Power not been integrated into the PJM market. The benefits were quantified by comparing the aggregate integrated PJM market results to the aggregate simulated market results. In general, the economic benefits of the integrated market dispatch fell into the following two categories:

- Savings incurred by demand in the PJM West (AP) region in the integrated (actual) market during times when it was able to import power from the rest of PJM at a lower price than it could import in the simulated case assuming historic transfer patterns. The savings incurred were as a result of replacing power that had been formerly generated within the PJM West region at a higher price or imported at a higher price from other regions in the eastern interconnection. This situation occurred approximately 3000 hours during the study period.

- Savings incurred by demand in the PJM East region in the integrated (actual) market during times when it was able to import power from PJM West at a lower price than it could import in the simulated case assuming historic transfer patterns. The savings incurred were a result of replacing power that had been formerly generated within the PJM East region at a higher price or imported at a higher price from elsewhere in the eastern interconnection. This situation occurred approximately 2400 hours during the study period.

The savings that were quantified in these situations accounted for the fact that there were economic transfers between AP and PJM prior to the integration of AP into the PJM energy market. This means that the quantified savings that are reported in this analysis were essentially adjusted downwards to account for the historic transfer levels of economic power from AP to PJM that occurred prior to the integration of Allegheny Power into the PJM market.

The results indicated that the overall savings were approximately $99,000,000 for the eight month study period. Of the total savings, approximately $40,730,000 occurred in the PJM West (AP) region. The remaining $58,290,000 in cost savings occurred in the PJM East region.

EXHIBIT

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These results do not include any benefits resulting directly from the elimination of transmission rate pancaking that occurred when PJM West was implemented. The elimination of the PJM export charges for transfers to PJM West did, however, eliminate a barrier to trade between the two regions which resulted in some of the efficiency gains that are quantified above.

These results also do not include the PJM Schedule 9, market administration, fees that are paid by Allegheny Power under the integrated market and would not have been paid had Allegheny not joined PJM. For the study period, these payments were approximately $13 Million.

## Market Data and Information

PJM has a CD containing the following information which will be supplied to the Commission upon request, if necessary:

1. Hourly Electric Demand in PJM and PJM West

   This file contains the hourly electric demand in MW that occurred in the PJM Real-time Energy Market for the PJM control area and the PJM West control area for the period April 1, 2002 – November 30, 2002

2. Hourly PJM Locational Marginal Prices

   This file contains the hourly integrated PJM Real-time Energy Market Locational Marginal Prices for the period April 1, 2002 – November 30, 2002. The following Locational Marginal Prices are listed in the files:

   - PJM Load-Weighted Average LMP
   - PSEG Zone LMP
   - PECO Zone LMP
   - PPL Zone LMP
   - BGE Zone LMP
   - JCPL Zone LMP
   - PENELEC Zone LMP
   - METED Zone LMP
   - PEPCO Zone LMP
   - AECO Zone LMP
   - DPL Zone LMP
   - GPU Zone LMP
   - APS Zone LMP
   - RECO Zone LMP
   - EASTERN HUB LMP
   - NEW JERSEY HUB LMP
   - WEST INT HUB LMP
   - WESTERN HUB LMP

3. Daily Energy Offers into the PJM Energy Market

This file contains the Daily Energy Offers that were submitted into the PJM Energy Market and which are the basis for determining the PJM Energy Market clearing prices

4. PJM Network Transmission Model

   This file contains the PJM powerflow model of the entire PJM and PJM West Transmission system in PTI Version 26 format

5. PJM Transmission Contingency File

   This file contains the transmission contingencies and monitored facilities that are the basis for the transmission constraints that are modeled in the PJM energy market operations through the security-constrained economic dispatch.

6. PJM load apportionment file

   This file contains the information required to model the distribution of zonal load to each electrical substation in the Network model.